Exhibit No.:	
Issues:	Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Ag Processing Inc; Federal Executive Agencies; Midwest Energy Consumer's Group; Midwest Energy Users' Association; and Missouri Industrial Energy Consumers
Case No.:	ER-2012-0175
Date Testimony Prepared:	August 21, 2012

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))))	**Case No. ER-2012-0175** Tracking No. YE-2012-0405

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Ag Processing Inc
Federal Executive Agencies
Midwest Energy Consumer's Group
Midwest Energy Users' Association
Missouri Industrial Energy Consumers

August 21, 2012

BRUBAKER & ASSOCIATES, INC.

Project 9594

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	)	**Case No. ER-2012-0175** Tracking No. YE-2012-0405

STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Ag Processing Inc; Federal Executive Agencies; Midwest Energy Consumer's Group; Midwest Energy Users' Association; and Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and schedules which were prepared in written form for introduction into evidence in the Missouri Public Service Commission's Case No. ER-2012-0175.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

M E Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 20th day of August, 2012.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2015
Commission # 11024862

Tammy S Klossner
Notary Public

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))))	**Case No. ER-2012-0175** Tracking No. YE-2012-0405

Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and President of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of Ag Processing Inc; Federal Executive Agencies; Midwest Energy Consumer's Group; Midwest Energy Users' Association; and Missouri Industrial Energy Consumers (collectively referred to as "Industrials"). These customers purchase substantial amounts of electricity from KCP&L Greater Missouri Operations Company ("GMO"), both in the MPS territory and in the L&P

territory. The outcome of this proceeding will have an impact on their cost of electricity.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of a class cost of service study for MPS and L&P, to explain how the study should be used, to recommend an appropriate allocation of any rate increase, and to make rate design recommendations.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A First, I present an overview of cost of service principles and concepts. This includes a description of how electricity is produced and distributed as well as a description of the various functions that are involved; namely, generation, transmission and distribution. This is followed by a discussion of the typical classification of these functionalized costs into demand-related costs, energy-related costs and customer-related costs.

With this as a background, I then explain the various factors which should be considered in determining how to allocate these functionalized and classified costs among customer classes.

Finally, I present the results of the detailed cost of service analyses for MPS and L&P. Because of the similarity of the issues, and in order to avoid unnecessary repetition, I will discuss these issues primarily in the context of MPS. The same principles apply to L&P. I have created two sets of schedules, one set designated as "MPS" and the other set designated as "L&P." The cost studies indicate how individual customer class revenues compare to the costs incurred in providing service to them. This analysis and interpretation is then followed by recommendations with respect to the alignment of class revenues with class costs.

Summary

Q PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A My testimony and recommendations may be summarized as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level of rates charged to customers.

2. GMO exhibits significant summer peak demands as compared to demands in other months, although L&P also has a fairly large winter peak as well.

3. There are two generally accepted methods for allocating generation and transmission fixed costs that would apply to GMO. These are the coincident peak methodology and the average and excess ("A&E") methodology.

4. The A&E methodology appropriately considers both class maximum demands and class load factor, as well as diversity between class peaks and the system peak.

5. In order to better reflect cost-causation, I have changed GMO's submitted cost of service methodology in two respects:

   (1) For generation fixed costs, GMO has used an obscure and inappropriate method to allocate generation fixed costs, which I will address in my rebuttal testimony. I have, instead, applied main-stream methods that this Commission has previously endorsed.

   (2) GMO has allocated off-system sales revenue using fixed cost allocation factors. An energy allocation factor, as previously approved by this Commission, should be used instead.

6. The results of my class cost of service study, incorporating the changes in methodology that I have applied, are summarized on Schedule MEB-COS-4. Schedule MEB-COS-5 shows the adjustments required to move each class to its cost of service on a revenue neutral basis at present rates.

7. A modest realignment of class revenues to move them closer to costs should be implemented, as presented on Schedule MEB-COS-6.

COST OF SERVICE PROCEDURES

Overview

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A The objective of *cost allocation* is to determine what proportion of the utility's total revenue requirement should be recovered from each customer class. As an aid to this determination, cost of service studies are usually performed to determine the portions of the total costs that are incurred to serve each customer class. The cost of service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design. For many regulators, cost-based rates are an expressed goal. To better interpret cost allocation and cost of service studies, it is important to understand the production and delivery of electricity.

Electricity Fundamentals

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

A No. Electricity is different from most other goods or services purchased by consumers. For example:

- It cannot be stored; must be delivered as produced;
- It must be delivered to the customer's home or place of business;
- The delivery occurs instantaneously when and in the amount needed by the customer; and
- Both the total quantity used (energy or kWh) by a customer <u>and</u> the rate of use (demand or kW) are important.

These unique characteristics differentiate electric utilities from other service-related industries.

The service provided by electric utilities is multi-dimensional. First, unlike most vital services, electricity must be delivered at the place of consumption – homes, schools, businesses, factories – because this is where the lights, appliances, machines, air conditioning, etc. are located. Thus, every utility must provide a path through which electricity can be delivered regardless of the customer's **demand** and **energy** requirements at any point in time.

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, air conditioning, perhaps heating, and to operate various appliances. At any instant, several appliances may be operating (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and when reflects the second dimension of utility service – the rate of electricity use or **demand**. The demand imposed by customers is an especially important characteristic because the maximum demands determine how much capacity the utility is obligated to provide.

Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can safely be imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 2,000 MW of electricity, the utility must have at least 2,000 MW of generation, plus additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and air conditioning systems cool our homes, schools, offices, and factories.

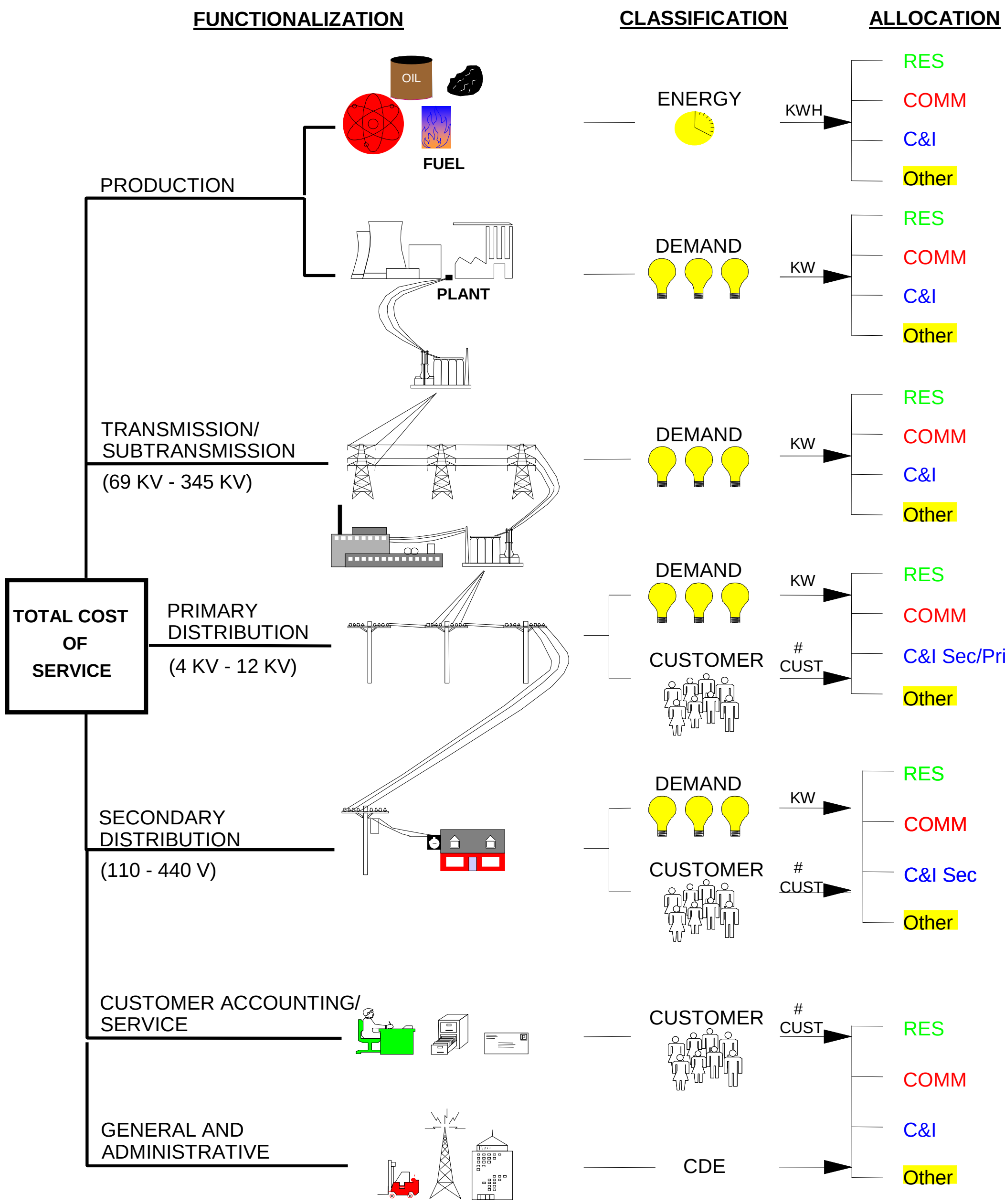
Satisfying customers' demand for electricity over time – providing **energy** – is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kWhs. To see one reason why this isn't so, consider a more familiar commodity – tomatoes, for example.

The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the <u>service</u> of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be even cheaper.

As illustrated in Figure 1, electric utilities are similar, except that in most cases (including Missouri), a single company handles everything from production on down through wholesale (bulk and area transmission) and retail (distribution to homes and stores). The crucial difference is that, unlike producers and distributors of tomatoes, electric utilities have an obligation to provide continuous reliable service. The obligation is assumed in return for the exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kWh) requirements of its customers, the obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

Q PLEASE EXPLAIN HOW A COST OF SERVICE STUDY IS PREPARED.

A To the extent possible, the unique characteristics that differentiate electric utilities from other service-related industries should be recognized in determining the cost of providing service to each of the various customer classes. The basic procedure for conducting a class cost of service study is simple. In an allocated cost of service study, we identify the different types of costs (**functionalization**), determine their primary causative factors (**classification**) and then apportion each item of cost among the various rate classes (**allocation**). Adding up the individual pieces gives the total cost for each customer class.

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

A Identifying the different levels of operation is a process referred to as **functionalization**. The utility's investment and expenses are separated by function (production, transmission, etc.). To a large extent, this is done in accordance with the Uniform System of Accounts.

Referring to Figure 1, at the top level there is generation. The next level is the extra high voltage transmission and subtransmission system (69,000 volts to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution – 4,160 to 12,000 volts. Finally, the voltage is stepped down by pole transformers at the "secondary" level to 110-440 volts used to serve homes, barbershops, light manufacturing and the like. Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltage.

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but when you buy a kWh at home you're not only buying the energy itself but also the service of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like Large Power Service customers – pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment, or pay separately for some services.)

Classification

Q WHAT IS CLASSIFICATION?

A Once the costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as **classification**. Costs are classified as demand-related, energy-related or customer-related.

Looking at the production function, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 2,000 MW – it must install and/or contract for enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance ("O&M") expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kWhs generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned – and therefore the amount of fuel expense – is closely related to the amount of energy (number of kWhs) that customers use. Therefore, fuel expense is an energy-related cost.

Most other O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.

Customer-related costs are the third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

A certain portion of the cost of the distribution system – poles, wires and transformers – is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

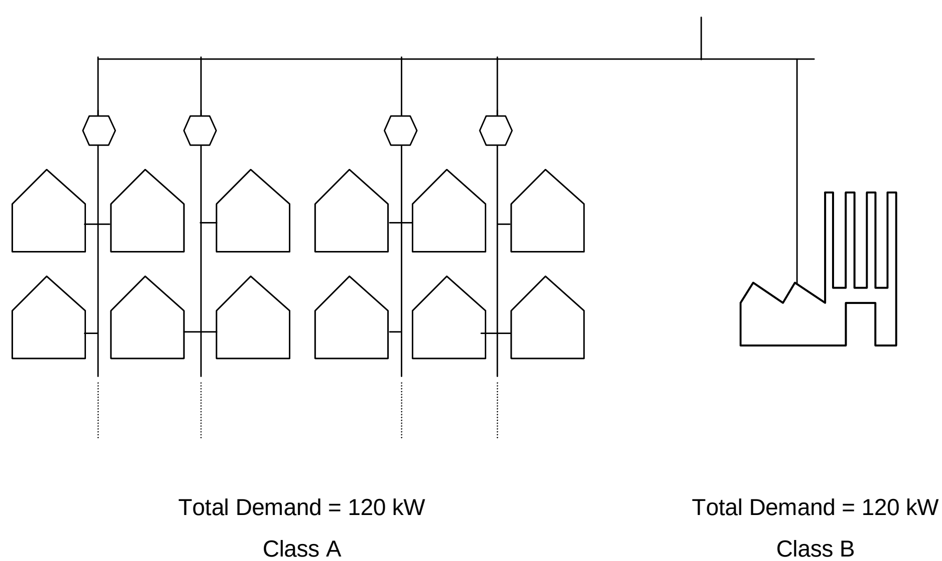
Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2

Classification of Distribution Investment



Demand vs. Energy Costs

Q WHAT IS THE DISTINCTION BETWEEN DEMAND-RELATED COSTS AND ENERGY-RELATED COSTS?

A The difference between demand-related and energy-related costs explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3 compares the electrical requirements of two customers, A and B, each using 100-watt light bulbs.

Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy – 1,000 watthours or 1 kWh. However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kW, than Customer B who demanded only 200 watts per hour or 0.2 kW.

Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 times Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

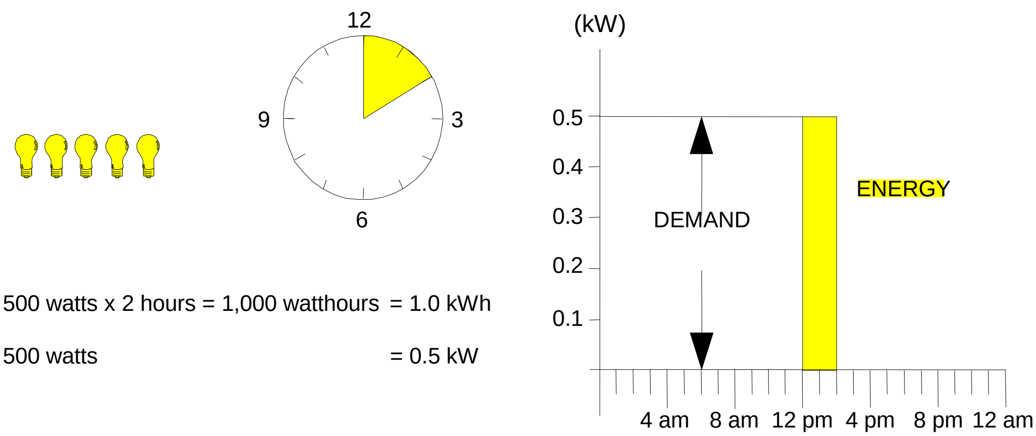
Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kWhs used for each kilowatt of demand imposed on the system is much greater in the case of Customer B.

Figure 3

DEMAND VS. ENERGY

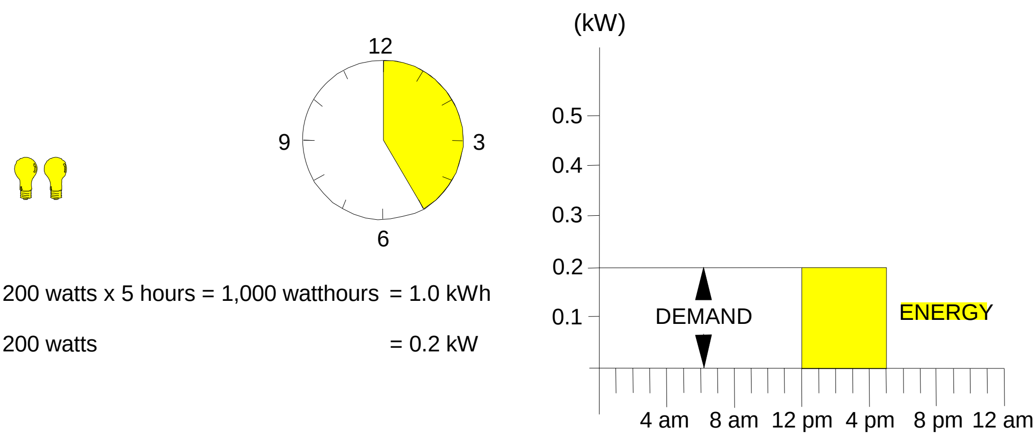
CUSTOMER A



ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

DEMAND: 500 watts = 0.5 kW

CUSTOMER B



ENERGY: 200 watts x 5 hours = 1,000 watthours = 1.0 kWh

DEMAND: 200 watts = 0.2 kW

Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kWh basis, than a customer with a low load factor, irrespective of size.

Consider also the analogy of a rental car which costs \$40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be \$2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the <u>average total</u> cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kWh will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industrial customers generally have higher load factors than residential or commercial customers, they are less costly to serve on a per-kWh basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

<u>Allocation</u>

Q WHAT IS ALLOCATION?

A The final step in the cost of service analysis is the **allocation** of the costs to the customer classes. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. For demand-related costs, we construct an allocation factor by looking at the important class demands.

Utility System Characteristics

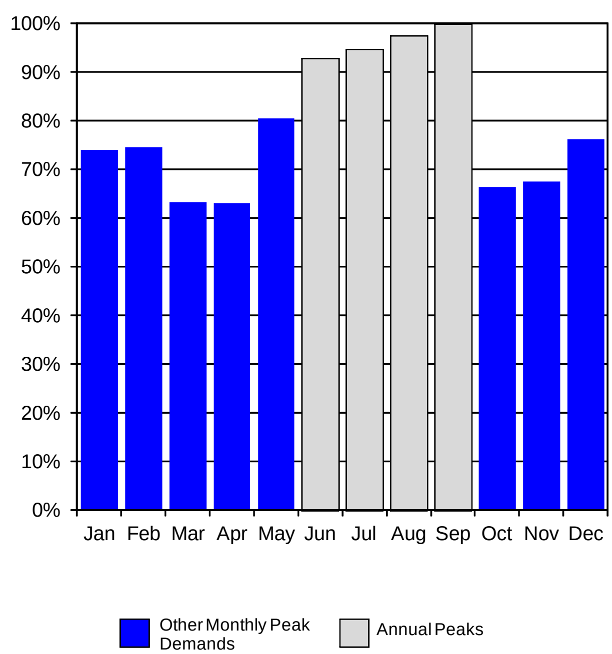
Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed, or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for MPS are shown on Schedule MEB-COS-MPS-1. For convenience, it is also shown here as Figure 4.

Figure 4

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Analysis of KCP&L Greater Missouri Operations Company
For All Territories Served as MPS
Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended September 30, 2011



This shows the monthly system peak demands for the test year used in the study. The highlighted bars show the months in which the highest peak occurred.

This analysis shows that summer peaks dominate. (This same information is presented in tabular form on Schedule MEB-COS-MPS-2.) This clearly shows that the two highest system peaks occurred in August and September. These peaks are substantially higher than the monthly peaks occurring in most other months. The peaks in June and July were 7% and 5%, respectively, lower than the annual peak.

Q WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?

A The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that caused the utility to incur capacity costs.

Q WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?

A As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class's contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then demands in all months may be important.

Q WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE GMO SYSTEM?

A As noted, the MPS load pattern has predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission costs. Demands in other months are of much less significance, do not compel the addition of generation capacity to serve them and should not be used in determining the allocation of costs.

Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?

A The two most predominantly used allocation methods in the industry are the coincident peak method and the A&E demand method.

The coincident method utilizes the demands of customer classes occurring at the time of the system peak or peaks selected for allocation. In the case of MPS, this would be one or more peaks occurring during the summer.

Q WHAT IS THE A&E METHOD?

A The A&E method is one of a family of methods which incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system “excess” demand is the difference between the system peak demand and the system average demand.

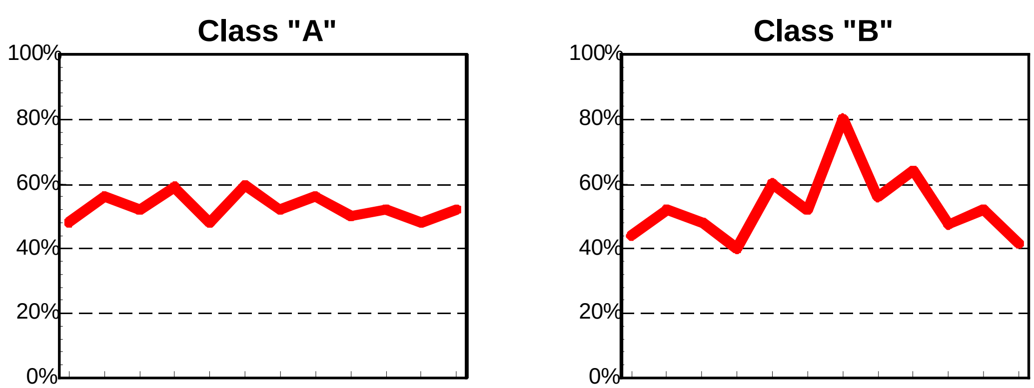
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their “peaking” or variability in usage.[1]

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

A As an example, Figure 5 shows two classes that have different monthly usage patterns.

Figure 5

<u>Load Patterns</u>



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has a much greater maximum demand[2] than

[1]<u>NARUC Electric Utility Cost Allocation Manual</u>, 1992, page 81.

[2]During any specified time period (e.g., month, year), the maximum demand of a class, regardless of when it occurs, is called the non-coincident peak demand.

Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment, resulting in higher maintenance cost.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).

Q WHAT DEMAND ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR GENERATION AND TRANSMISSION?

A First, in order to reflect cost-causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

Either a coincident peak study, using the demands during the summer (peak) months, or a version of an A&E cost of service study that uses class non-coincident peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I will make my recommendations based on the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

Based on test year load characteristics, I believe the most appropriate A&E allocation would be using August and September system peaks. However, the allocation factors for all classes under that approach are very close to the A&E-4NCP allocation factors.

Schedule MEB-COS-3 shows the derivation of the A&E demand allocation factor for generation using the four annual class non-coincident peaks.

Q REFERRING TO SCHEDULE MEB-COS-3, PLEASE EXPLAIN THE DEVELOPMENT OF THE A&E ALLOCATION FACTOR.

A Line 2 shows the average of the four non-coincident peaks for each class. Line 3 shows the annual amount of energy required by each class. Line 4 is the average demand, in kilowatts, which is determined by dividing the annual energy in line 3 by the number of hours (8,760) in a year. Line 5 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown on line 6, is equal to the non-coincident peak demand shown on line 2 minus the average demand that is shown on line 4. Line 7 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total excess demand for all classes.

Finally, line 10 presents the composite A&E allocation factor. It is determined by weighting the average demand responsibility of each class (which is the same as each class's energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

Q IT IS NOTED THAT WHILE MPS HAS A PREDOMINANT SUMMER PEAK, L&P HAS PREDOMINANT PEAKS IN BOTH SUMMER AND WINTER. IS THE SAME ALLOCATION METHOD APPROPRIATE FOR BOTH?

A Yes. The A&E-4NCP methodology is appropriate for both. In the case of MPS, data from the four peak months occurring in the summer is used. In the case of L&P, data from the two highest summer peaks and the two highest winter peaks is used.

Making the Cost of Service Study – Summary

Q PLEASE SUMMARIZE THE PROCESS AND THE RESULTS OF A COST OF SERVICE ANALYSIS.

A As previously discussed, the cost of service procedure involves three steps:

1. Functionalization – Identify the different functional "levels" of the system;
2. Classification – Determine, for each functional type, the primary cause or causes (customer, demand or energy) of that cost being incurred; and
3. Allocation – Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

A The results are presented in Schedule MEB-COS-4, which reflects results at present rates.

Q REFERRING TO SCHEDULE MEB-COS-4, PLEASE EXPLAIN THE ORGANIZATION AND WHAT IS SHOWN.

A Schedule MEB-COS-4 is a summary of the key elements and the results of the class cost of service study. The top section of the schedule shows the revenues, expenses and operating income based on an A&E-4NCP cost of service study.

The next section shows the major elements of rate base, and the rate of return at present rates for each customer class based on this cost of service study.

Q DID GMO SUBMIT CLASS COST OF SERVICE STUDIES?

A Yes. GMO submitted a class cost of service study for each territory. These studies base the allocation of generation costs on an obscure and inappropriate allocation method. GMO's method is not grounded in appropriate cost causation principles, and should not be accepted. I will address this proposed methodology in more detail in my rebuttal testimony.

Q HAVE YOU USED ITS STUDY?

A I have used the study framework as a basis for preparing my cost of service study. As explained below, I have developed a cost of service study using a different allocation for generation fixed costs, and also a different allocation of the margin on off-system sales.

Q HAVE YOU PREPARED ANY COST OF SERVICE STUDIES BESIDES THE A&E-4NCP STUDY PRESENTED IN SCHEDULE MEB-COS-4?

A Yes. I have prepared studies based on A&E-2NCP, and also 4CP methodologies. The derivation of the generation capacity allocation factor and the results of each cost of service study are presented in the Appendix to my schedules.

Q OTHER THAN THE USE OF A DIFFERENT ALLOCATION FOR GENERATION FIXED COSTS, HOW DO YOUR STUDIES DIFFER FROM THE ONES PRESENTED BY GMO?

A There also is a difference in the allocation of the revenue from off-system sales.

Q WHAT IS THE ISSUE WITH RESPECT TO THE ALLOCATION OF OFF-SYSTEM SALES?

A GMO has allocated the revenues from off-system sales on the basis of measures of class demands.

The more traditional approach is to allocate the revenues from off-system sales to customer classes on the basis of class kWh requirements. This would make the allocation of the revenues consistent with the allocation of the underlying costs. (This method was recently adopted in a KCPL rate case, Case No. ER-2006-0314, and re-affirmed in Ameren Missouri's rate case, Case No. ER-2010-0036.)

Q HOW DID YOU USE GMO'S COST OF SERVICE MODEL IN PRODUCING YOUR CLASS COST OF SERVICE STUDY?

A It was the starting point. The results of GMO's allocation first were replicated by utilizing the data contained in its cost of service model. Many of GMO's allocation factors and functionalizations and classifications have been utilized. The principal areas where I depart from GMO and use a different approach were incorporated into the allocations. They have previously been explained in this testimony.

I disagree with GMO's allocation of certain DSM costs on a production demand basis, but have not made a change in the attached COS studies because all of the relevant costs could not be identified. I will address this issue in my rebuttal testimony.

Adjustment of Class Revenues

Q WHAT SHOULD BE THE PRIMARY BASIS FOR ESTABLISHING CLASS REVENUE REQUIREMENTS AND DESIGNING RATES?

A Cost should be the primary factor used in both steps.

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the primary basis used to establish the revenues collected from each customer class and to design rate schedules.

Factors such as simplicity, gradualism and ease of administration may also be taken into account, but the basic starting point and guideline throughout the process should be cost of service. To the extent practicable, rate schedules should be structured and designed to reflect the important cost-causative features of the service provided, and to collect the appropriate cost from the customers within each class or rate schedule, based upon the individual load patterns exhibited by those customers.

Electric rates also play a role in economic development, both with respect to job creation and job retention. This is particularly true in the case of industries where electricity is a large component of the cost of production.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT COST BE USED AS THE PRIMARY FACTOR FOR THESE PURPOSES?

A The basic reasons for using cost as the primary factor are equity, conservation, and engineering efficiency (cost-minimization).

Q PLEASE EXPLAIN HOW EQUITY IS ACHIEVED BY BASING RATES ON COST.

A When rates are based on cost, each customer pays what it costs the utility to provide service to that customer; no more and no less. If rates are based on anything other than cost factors, then some customers will pay the costs attributable to providing service to other customers – which is inherently inequitable.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be mislead into using electricity inefficiently in response to the distorted rate design signals they receive.

Q WILL COST-BASED RATES ASSIST IN THE DEVELOPMENT OF COST-EFFECTIVE DEMAND-SIDE MANAGEMENT ("DSM") PROGRAMS?

A Yes. The success of DSM (both energy efficiency and demand response programs) depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is subsidized by other customers; that is, the bill is determined using rates which are below cost, that customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

For example, assume that the relevant cost to produce and deliver energy is 8¢ per kWh. If a customer has an opportunity to install energy efficiency or DSM equipment that would allow the customer to reduce energy use or demand, the customer will be much more likely to make that investment if the price of electricity equals the cost of electricity, i.e., 8¢ per kWh, than if the customer is receiving a subsidized rate of 6¢ per kWh.

Q HOW DO COST-BASED RATES ACHIEVE THE COST-MINIMIZATION OBJECTIVE?

A When the rates are designed so that the energy costs, demand costs and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

If a utility attempts to extract a disproportionate share of revenues from a class that has alternatives available (such as producing products at other locations where costs are lower), then the utility will be faced with the situation where it must discount the rates or lose the load, either in part or in total. To the extent that the load could have been served more economically by the utility, then either the other customers of the utility or the stockholders (or some combination of both) will be worse off than if the rates were properly designed on the basis of cost.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from large customers and high load factor customers. To the extent that these customers may have lower cost alternatives than do the smaller or the low load factor customers, the same problems noted above are created.

Revenue Allocation

Q PLEASE REFER AGAIN TO SCHEDULE MEB-COS-4 FOR MPS AND SUMMARIZE THE RESULTS OF YOUR CLASS COST OF SERVICE STUDY.

A As indicated on the last two lines on Schedule MEB-COS-4, movement of all classes to cost of service will require an increase to the Residential class and a decrease to all other classes.

Q WHAT ADJUSTMENTS TO REVENUES WOULD BE REQUIRED AT PRESENT RATES TO MOVE ALL CLASSES TO COST OF SERVICE?

A This is shown on Schedule MEB-COS-5 for MPS. The first five columns summarize the results of the cost of service study at present rates, and are taken from Schedule MEB-COS-4. The remaining columns of Schedule MEB-COS-5 determine the amount of increase or decrease, on a revenue neutral basis, required to move each customer class to the average rate of return at current revenue levels. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall increase in revenues. Note that the Residential class would require an increase of about $22 million, or 7.2%, in order to move to cost of service. All other classes would require a corresponding decrease. The decreases range from about 7% for the Large General Service class to 11% for the Lighting class.

Q PLEASE REFER TO SCHEDULE MEB-COS-4 AND MEB-COS-5 FOR L&P AND EXPLAIN THE RESULTS.

A For L&P, the Residential class is below cost of service. All other classes are above cost of service. Moving to cost of service would require a 10% increase for residential customers. All other classes would require a corresponding decrease. The decreases range from about 6% for the Large Power Service class to 21% for the Lighting class.

Q HOW DOES GMO PROPOSE TO ADJUST REVENUES?

A GMO proposes essentially an equal percentage across-the-board increase.

Q WOULD GMO'S ALLOCATION MOVE CLASS RATES CLOSER TO COST OF SERVICE?

A No. GMO's allocation would essentially maintain the status quo in which the Residential class is below cost of service, while all other classes are above cost of service.

Q DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR ALLOCATION OF MPS'S REVENUE REQUIREMENT?

A Yes. I will focus on adjustments to be made on a revenue neutral basis at present rates. After having made my recommended revenue neutral adjustments at present rates, any overall change in revenues allowed to GMO can then be applied on an equal percentage across-the-board basis to these adjusted class revenues.

Q PLEASE EXPLAIN YOUR SPECIFIC PROPOSAL.

A My specific proposal is shown on Schedule MEB-COS-6 for MPS. Column 1 shows class revenues at current rates. Column 2 shows my proposed cost of service adjustment. This adjustment moves classes roughly 25% of the way toward cost of service. This 25% movement was selected because it makes a reasonable step in the right direction without imposing too disruptive of a revenue increase on the Residential class. An overall revenue-neutral increase of about 1.8% on the Residential class is a relatively modest step, but at least it is a step in the right direction.

Q WHAT IS YOUR SPECIFIC PROPOSAL FOR L&P?

A My specific proposal is shown on Schedule MEB-COS-6 for L&P. Column 1 shows class revenues at current rates. Column 2 shows my proposed cost of service adjustments. This adjustment moves classes roughly 25% of the way toward cost of service. This 25% movement was selected because it makes a reasonable step in the right direction without imposing too disruptive of a revenue increase on the Residential class.

My recommendation of moving 25% of the way toward cost of service limits the L&P Residential class revenue-neutral increase to 2.4% (as compared to the 10% increase required to move all the way to cost of service).

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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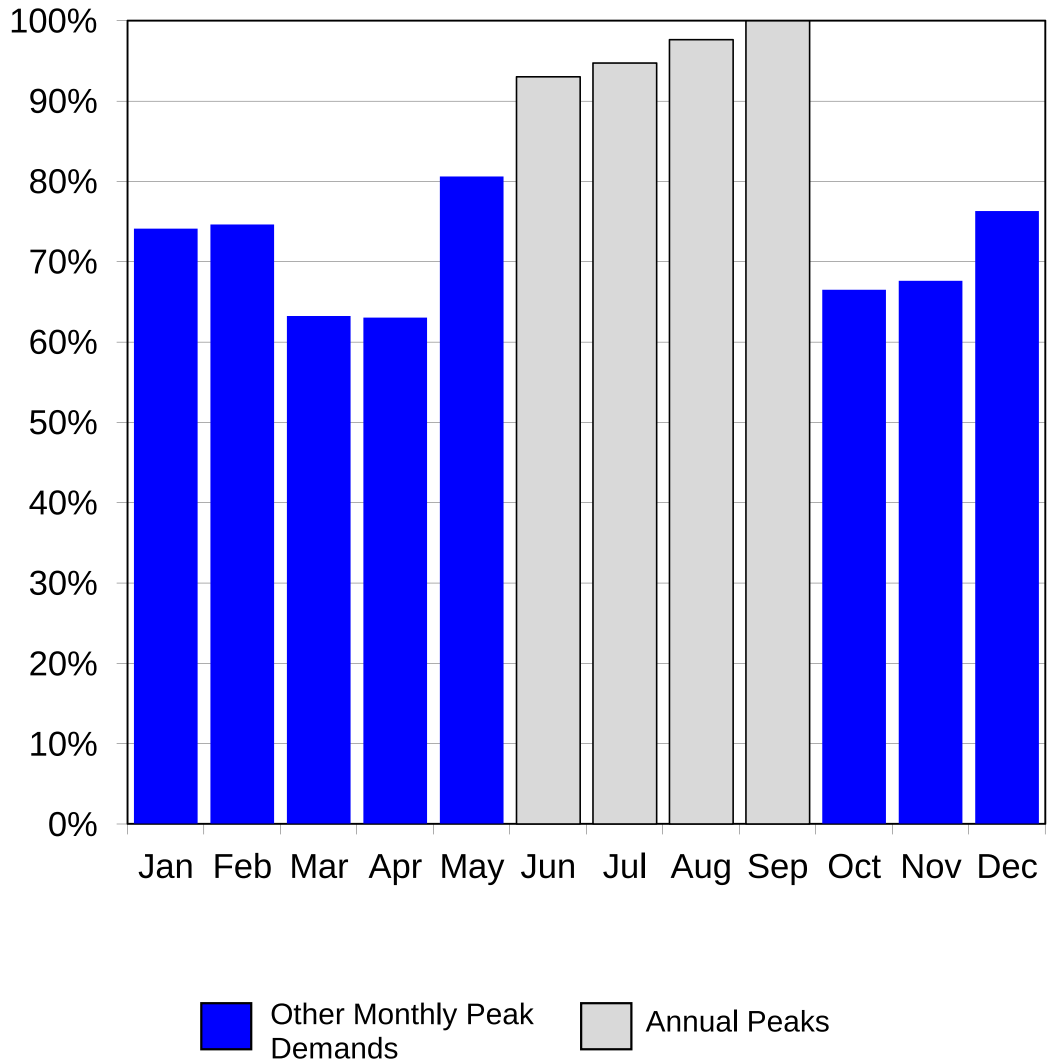
KCP&L GREATER MISSOURI OPERATIONS COMPANY

Analysis of KCP&L Greater Missouri Operations Company
For All Territories Served as MPS
Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended September 30, 2011



KCP&L GREATER MISSOURI OPERATIONS COMPANY

Analysis of KCP&L Greater Missouri Operations Company
For All Territories Served as MPS
Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended September 30, 2011

Line	Description	MPS Retail MW (1)	Percent (2)
1	January	1,129	74.1
2	February	1,137	74.6
3	March	963	63.2
4	April	960	63.1
5	May	1,228	80.6
6	June	1,417	93.0
7	July	1,443	94.8
8	August	1,487	97.6
9	September	1,523	100.0
10	October	1,013	66.5
11	November	1,030	67.6
12	December	1,162	76.3

Source: GMO Allocators MPS Rev 2-23-12.xls

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS MPS

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended September 30, 2011

Line	Description	MPS Retail	Residential	Small General Service	Large General Service	Large Power Service	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)
1	Territory System Peak - kW	1,523,232					
2	Avg of 4 Highest Monthly NCP Values - kW	1,651,349	963,310	214,036	224,522	243,810	5,672
3	Energy Sales with Losses - MWh	6,384,243	2,989,076	847,386	1,018,112	1,479,985	49,685
4	Average Demand - kW	728,795	341,219	96,734	116,223	168,948	5,672
5	Average Demand - Percent	1.000000	0.468196	0.132731	0.159473	0.231818	0.007782
6	Class Excess Demand - kW	922,554	622,091	117,302	108,299	74,862	-
7	Class Excess Demand - Percent	1.000000	0.674314	0.127150	0.117390	0.081147	-
	Allocator:						
8	Annual Load Factor * Average Demand	0.478453	0.224010	0.063505	0.076300	0.110914	0.003724
9	(1-LF) * Excess Demand	0.521547	0.351686	0.066314	0.061224	0.042322	-
10	Average and Excess Demand Allocator	1.000000	0.575696	0.129820	0.137525	0.153236	0.003724

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	47.85%
1 - Load Factor	52.15%

Source: GMO Allocators MPS Rev 2-23-12.xls

Schedule MEB-COS-MPS-3

KCP&L Greater Missouri Operations - MPS
2012 RATE CASE - Direct Filing
TY 9/30/11; Update TBD; K&M 8/31/12
Cost of Service

LINE NO.	DESCRIPTION	MPS RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**						
0020							
0030	OPERATING REVENUE						
0040	RETAIL SALES REVENUE	537,210,996	292,767,974	78,158,277	71,472,490	85,398,998	9,413,257
0050	OTHER SALES REVENUE (447)	10,935,074	5,220,806	1,452,514	1,720,380	2,458,538	82,835
0060	OTHER OPERATING REVENUE	5,913,364	3,345,773	801,469	781,577	884,430	100,115
0070	TOTAL OPERATING REVENUE	554,059,435	301,334,554	80,412,261	73,974,447	88,741,967	9,596,207
0080							
0090	OPERATING EXPENSES						
0100	FUEL	124,727,338	58,996,970	16,493,183	19,744,741	28,538,384	954,060
0110	PURCHASED POWER	53,901,882	25,703,417	7,191,865	8,489,262	12,076,838	440,500
0120	OTHER OPERATION & MAINTENANCE EXPENSES	181,319,987	118,269,351	24,773,634	18,416,589	17,479,579	2,380,834
0130	DEPRECIATION EXPENSES (AFTER CLEARINGS)	65,166,547	40,842,703	8,576,029	7,186,383	6,668,256	1,893,177
0140	AMORTIZATION EXPENSES	1,128,419	700,347	149,592	128,668	128,553	21,258
0150	TAXES OTHER THAN INCOME TAXES	21,899,083	13,541,365	2,907,720	2,506,016	2,496,856	447,127
0160	FEDERAL AND STATE INCOME TAXES	26,435,908	8,214,585	5,924,834	4,884,552	6,195,227	1,216,710
0170	TOTAL ELECTRIC OPERATING EXPENSES	474,579,165	266,268,736	66,016,857	61,356,212	73,583,693	7,353,666
0180							
0190	NET ELECTRIC OPERATING INCOME	79,480,270	35,065,818	14,395,404	12,618,235	15,158,273	2,242,540
0200							
0210	RATE BASE						
0220	TOTAL ELECTRIC PLANT	2,373,092,507	1,465,275,215	313,353,734	273,064,356	268,049,336	53,349,866
0230	LESS: ACCUM. PROV. FOR DEPREC	826,157,774	518,568,974	108,802,718	90,515,201	87,269,782	21,001,099
0240	NET PLANT	1,546,934,733	946,706,241	204,551,016	182,549,155	180,779,555	32,348,766
0250	PLUS:						
0260	CASH WORKING CAPITAL	(24,540,361)	(14,337,860)	(3,428,201)	(3,025,975)	(3,267,083)	(481,242)
0270	MATERIALS & SUPPLIES	27,179,644	16,782,177	3,588,922	3,127,477	3,070,039	611,030
0280	EMISSION ALLOWANCES	2,639,993	1,521,959	349,076	354,368	404,760	9,830
0290	PREPAYMENTS	1,546,533	954,913	204,211	177,955	174,686	34,768
0300	FUEL INVENTORY	31,118,207	14,719,146	4,114,882	4,926,113	7,120,038	238,028
0310	AAO DEF DIBLEY REB & WESTERN COAL 1990	8,912	5,138	1,178	1,196	1,366	33
0320	AAO DEF DIBLEY REB & WESTERN COAL 1992	121,294	69,926	16,038	16,281	18,597	452
0330	DEFERRAL OF DSM/EE COSTS	24,777,654	13,243,281	3,420,449	3,576,214	4,270,939	266,772
0340	REGULATORY ASSETS	46,102,215	28,211,627	6,171,724	5,434,295	5,850,702	433,868
0350	LESS:						
0360	CUSTOMER ADVANCES FOR CONSTRUCTION	2,356,990	1,551,499	300,269	212,935	170,963	121,325
0370	CUSTOMER DEPOSITS	5,143,148	2,673,233	2,383,293	80,154	6,468	0
0380	TOTAL ACCUMULATED DEFERRED TAXES	236,349,964	145,935,206	31,208,705	27,196,053	26,696,579	5,313,421
0390	TOTAL ACCUMULATED DEFERRED TAXES - AAO	49,986	30,864	6,600	5,752	5,646	1,124
0400	TOTAL RATE BASE	1,411,988,738	857,685,746	185,090,428	169,642,185	171,543,943	28,026,436
0410							
0420	RATE OF RETURN	5.629%	4.088%	7.777%	7.438%	8.836%	8.002%
0430	RELATIVE RATE OF RETURN	1.00	0.73	1.38	1.32	1.57	1.42

Notes:
Production Plant and Expense Allocated using A&E-4NCP.
SFR Off System Sales Allocated on Energy.

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS MPS

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using Modified ECOS at Present Rates
($ in Thousands)

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Average Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 301,335	$ 857,686	$ 35,066	4.088%	73	$ 48,279	$ 13,213	$ 21,683	7.2%
2	Small General Service	80,412	185,090	14,395	7.777%	138	10,419	(3,977)	(6,526)	-8.1%
3	Large General Service	73,974	169,642	12,618	7.438%	132	9,549	(3,069)	(5,037)	-6.8%
4	Large Power Service	88,742	171,544	15,158	8.836%	157	9,656	(5,502)	(9,029)	-10.2%
5	Total Lighting	9,596	28,026	2,243	8.002%	142	1,578	(665)	(1,091)	-11.4%
6	Total	$ 554,059	$ 1,411,989	$ 79,480	5.629%	100	$ 79,480	$ (0)	$ (0)	0.0%

Source: Schedule MEB-COS-4

Schedule MEB-COS-MPS-5

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS MPS

Recommended Cost of Service Adjustments
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 25% Toward Cost Of Service (2)	Adjusted Current Revenue (3)	Percent of Adjusted Current Revenue (4)
1	Residential	$ 301.3	$ 5.4	$ 306.8	55.37%
2	Small General Service	80.4	(1.6)	78.8	14.22%
3	Large General Service	74.0	(1.3)	72.7	13.12%
4	Large Power Service	88.7	(2.3)	86.5	15.61%
5	Total Lighting	9.6	(0.3)	9.3	1.68%
6	Subtotal	$ 554.1	$ -	$ 554.1	100.00%

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS MPS

Development of
Average and Excess Demand Allocator
Based on 2 Non-Coincident Peaks
For the Test Year Ended September 30, 2011

Line	Description	MPS Retail	Residential	Small General Service	Large General Service	Large Power Service	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)
1	Territory System Peak - kW	1,523,232					
2	Avg of 2 Highest Monthly NCP Values - kW	1,667,521	988,054	213,168	225,543	235,084	5,672
3	Energy Sales with Losses - MWh	6,384,243	2,989,076	847,386	1,018,112	1,479,985	49,685
4	Average Demand - kW	728,795	341,219	96,734	116,223	168,948	5,672
5	Average Demand - Percent	1.000000	0.468196	0.132731	0.159473	0.231818	0.007782
6	Class Excess Demand - kW	938,726	646,835	116,434	109,320	66,136	-
7	Class Excess Demand - Percent	1.000000	0.689057	0.124034	0.116456	0.070453	-
	Allocator:						
8	Annual Load Factor * Average Demand	0.478453	0.224010	0.063505	0.076300	0.110914	0.003724
9	(1-LF) * Excess Demand	0.521547	0.359375	0.064690	0.060737	0.036745	-
10	Average and Excess Demand Allocator	1.000000	0.583385	0.128195	0.137037	0.147659	0.003724

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	47.85%
1 - Load Factor	52.15%

Source: GMO Allocators MPS Rev 2-23-12.xls

KCP&L Greater Missouri Operations - MPS
2012 RATE CASE - Direct Filing
TY 9/30/11; Update TBD; K&M 8/31/12
Cost of Service

LINE NO.	DESCRIPTION	MPS RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**						
0020							
0030	OPERATING REVENUE						
0040	RETAIL SALES REVENUE	537,210,996	292,767,974	78,158,277	71,472,490	85,398,998	9,413,257
0050	OTHER SALES REVENUE (447)	10,935,074	5,226,057	1,449,440	1,722,521	2,454,221	82,835
0060	OTHER OPERATING REVENUE	5,913,364	3,349,316	799,395	783,021	881,517	100,115
0070	TOTAL OPERATING REVENUE	554,059,435	301,343,348	80,407,112	73,978,032	88,734,737	9,596,207
0080							
0090	OPERATING EXPENSES						
0100	FUEL	124,727,338	58,996,970	16,493,183	19,744,741	28,538,384	954,060
0110	PURCHASED POWER	53,901,882	25,703,417	7,191,865	8,489,262	12,076,838	440,500
0120	OTHER OPERATION & MAINTENANCE EXPENSES	181,319,987	118,648,431	24,551,669	18,571,128	17,167,925	2,380,834
0130	DEPRECIATION EXPENSES (AFTER CLEARINGS)	65,166,547	40,969,277	8,501,915	7,237,983	6,564,195	1,893,177
0140	AMORTIZATION EXPENSES	1,128,419	703,165	147,942	129,817	126,236	21,258
0150	TAXES OTHER THAN INCOME TAXES	21,899,083	13,593,098	2,877,428	2,527,106	2,454,325	447,127
0160	FEDERAL AND STATE INCOME TAXES	26,435,908	7,957,186	6,075,550	4,779,620	6,406,843	1,216,710
0170	TOTAL ELECTRIC OPERATING EXPENSES	474,579,165	266,571,543	65,839,553	61,479,656	73,334,746	7,353,666
0180							
0190	NET ELECTRIC OPERATING INCOME	79,480,270	34,771,804	14,567,559	12,498,375	15,399,991	2,242,540
0200							
0210	RATE BASE						
0220	TOTAL ELECTRIC PLANT	2,373,092,507	1,470,882,606	310,070,407	275,350,301	263,439,328	53,349,866
0230	LESS: ACCUM. PROV. FOR DEPREC	826,157,774	520,432,019	107,711,838	91,274,702	85,738,115	21,001,099
0240	NET PLANT	1,546,934,733	950,450,587	202,358,569	184,075,598	177,701,213	32,348,766
0250	PLUS:						
0260	CASH WORKING CAPITAL	(24,540,361)	(14,368,220)	(3,410,424)	(3,038,352)	(3,242,123)	(481,242)
0270	MATERIALS & SUPPLIES	27,179,644	16,846,400	3,551,317	3,153,658	3,017,239	611,030
0280	EMISSION ALLOWANCES	2,639,993	1,540,133	338,435	361,777	389,818	9,830
0290	PREPAYMENTS	1,546,533	958,567	202,071	179,444	171,682	34,768
0300	FUEL INVENTORY	31,118,207	14,719,146	4,114,882	4,926,113	7,120,038	238,028
0310	AAO DEF DIBLEY REB & WESTERN COAL 1990	8,912	5,199	1,142	1,221	1,316	33
0320	AAO DEF DIBLEY REB & WESTERN COAL 1992	121,294	70,761	15,549	16,622	17,910	452
0330	DEFERRAL OF DSM/EE COSTS	24,777,654	13,243,281	3,420,449	3,576,214	4,270,939	266,772
0340	REGULATORY ASSETS	46,102,215	28,384,429	6,070,542	5,504,740	5,708,636	433,868
0350	LESS:						
0360	CUSTOMER ADVANCES FOR CONSTRUCTION	2,356,990	1,551,499	300,269	212,935	170,963	121,325
0370	CUSTOMER DEPOSITS	5,143,148	2,673,233	2,383,293	80,154	6,468	0
0380	TOTAL ACCUMULATED DEFERRED TAXES	236,349,964	146,493,678	30,881,699	27,423,724	26,237,441	5,313,421
0390	TOTAL ACCUMULATED DEFERRED TAXES - AAO	49,986	30,982	6,531	5,800	5,549	1,124
0400	TOTAL RATE BASE	1,411,988,738	861,100,891	183,090,739	171,034,425	168,736,247	28,026,436
0410							
0420	RATE OF RETURN	5.629%	4.038%	7.956%	7.308%	9.127%	8.002%
0430	RELATIVE RATE OF RETURN	1.00	0.72	1.41	1.30	1.62	1.42

Notes:
Production Plant and Expense Allocated using A&E-2NCP.
SFR Off System Sales Allocated on Energy.

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS MPS

Development of
4 CP Demand Allocator
For the Test Year Ended September 30, 2011

Line	Description	MPS Retail	Residential	Small General Service	Large General Service	Large Power Service	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)
1	4 CP Demand - kW	1,454,734	829,216	200,566	198,340	226,613	-
2	4 CP Demand - Percent	1.000000	0.570012	0.137871	0.136341	0.155776	-

Source: GMO Allocators MPS Rev 2-23-12.xls

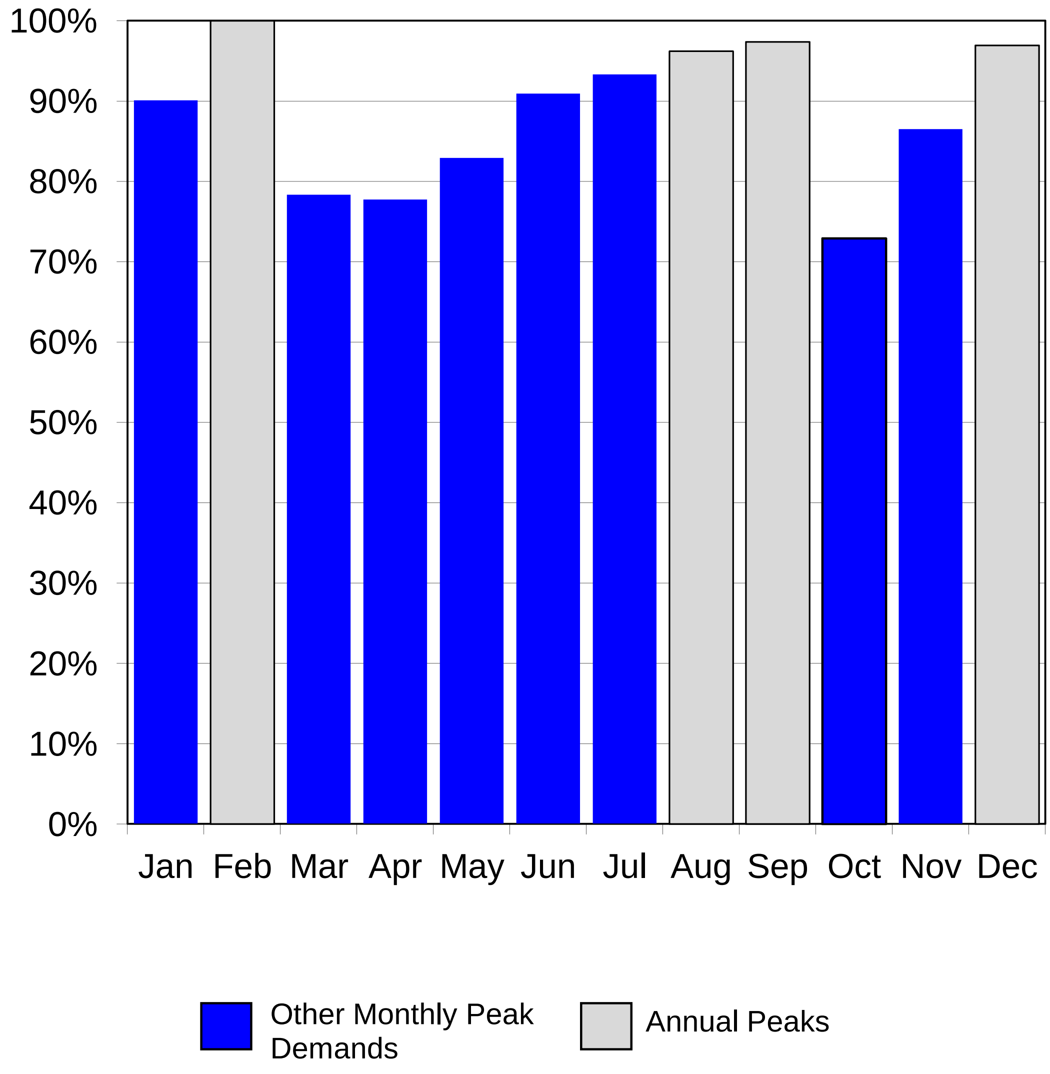
KCP&L Greater Missouri Operations - MPS
2012 RATE CASE - Direct Filing
TY 9/30/11; Update TBD; K&M 8/31/12
Cost of Service

LINE NO.	DESCRIPTION	MPS RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**						
0020							
0030	OPERATING REVENUE						
0040	RETAIL SALES REVENUE	537,210,996	292,767,974	78,158,277	71,472,490	85,398,998	9,413,257
0050	OTHER SALES REVENUE (447)	10,935,074	5,215,856	1,456,820	1,721,990	2,460,413	79,995
0060	OTHER OPERATING REVENUE	5,913,364	3,342,434	804,374	782,662	885,695	98,199
0070	TOTAL OPERATING REVENUE	554,059,435	301,326,264	80,419,472	73,977,142	88,745,106	9,591,450
0080							
0090	OPERATING EXPENSES						
0100	FUEL	124,727,338	58,996,970	16,493,183	19,744,741	28,538,384	954,060
0110	PURCHASED POWER	53,901,882	25,703,417	7,191,865	8,489,262	12,076,838	440,500
0120	OTHER OPERATION & MAINTENANCE EXPENSES	181,319,987	117,912,013	25,084,479	18,532,777	17,614,925	2,175,793
0130	DEPRECIATION EXPENSES (AFTER CLEARINGS)	65,166,547	40,723,388	8,679,819	7,225,178	6,713,447	1,824,714
0140	AMORTIZATION EXPENSES	1,128,419	697,690	151,904	129,532	129,559	19,734
0150	TAXES OTHER THAN INCOME TAXES	21,899,083	13,492,599	2,950,141	2,521,872	2,515,327	419,145
0160	FEDERAL AND STATE INCOME TAXES	26,435,908	8,457,220	5,713,768	4,805,660	6,103,326	1,355,934
0170	TOTAL ELECTRIC OPERATING EXPENSES	474,579,165	265,983,297	66,265,158	61,449,022	73,691,807	7,189,881
0180							
0190	NET ELECTRIC OPERATING INCOME	79,480,270	35,342,967	14,154,313	12,528,120	15,053,300	2,401,569
0200							
0210	RATE BASE						
0220	TOTAL ELECTRIC PLANT	2,373,092,507	1,459,989,449	317,951,777	274,783,016	270,051,382	50,316,883
0230	LESS: ACCUM. PROV. FOR DEPREC	826,157,774	516,812,788	110,330,409	91,086,223	87,934,958	19,993,397
0240	NET PLANT	1,546,934,733	943,176,661	207,621,368	183,696,793	182,116,424	30,323,487
0250	PLUS:						
0260	CASH WORKING CAPITAL	(24,540,361)	(14,309,241)	(3,453,096)	(3,035,280)	(3,277,923)	(464,820)
0270	MATERIALS & SUPPLIES	27,179,644	16,721,638	3,641,584	3,147,161	3,092,969	576,292
0280	EMISSION ALLOWANCES	2,639,993	1,504,828	363,979	359,939	411,248	0
0290	PREPAYMENTS	1,546,533	951,468	207,208	179,075	175,991	32,791
0300	FUEL INVENTORY	31,118,207	14,719,146	4,114,882	4,926,113	7,120,038	238,028
0310	AAO DEF DIBLEY REB & WESTERN COAL 1990	8,912	5,080	1,229	1,215	1,388	0
0320	AAO DEF DIBLEY REB & WESTERN COAL 1992	121,294	69,139	16,723	16,537	18,895	0
0330	DEFERRAL OF DSM/EE COSTS	24,777,654	13,243,281	3,420,449	3,576,214	4,270,939	266,772
0340	REGULATORY ASSETS	46,102,215	28,048,735	6,313,422	5,487,258	5,912,399	340,401
0350	LESS:						
0360	CUSTOMER ADVANCES FOR CONSTRUCTION	2,356,990	1,551,499	300,269	212,935	170,963	121,325
0370	CUSTOMER DEPOSITS	5,143,148	2,673,233	2,383,293	80,154	6,468	0
0380	TOTAL ACCUMULATED DEFERRED TAXES	236,349,964	145,408,766	31,666,651	27,367,225	26,895,974	5,011,348
0390	TOTAL ACCUMULATED DEFERRED TAXES - AAO	49,986	30,753	6,697	5,788	5,688	1,060
0400	TOTAL RATE BASE	1,411,988,738	854,466,485	187,890,837	170,688,924	172,763,276	26,179,218
0410							
0420	RATE OF RETURN	5.629%	4.136%	7.533%	7.340%	8.713%	9.174%
0430	RELATIVE RATE OF RETURN	1.00	0.73	1.34	1.30	1.55	1.63

Notes:
Production Plant and Expense Allocated using 4CP.
SFR Off System Sales Allocated on Energy.

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Analysis of KCP&L Greater Missouri Operations Company
For All Territories Served as L&P
Monthly Peak Demands
as a Percent of the Annual System Peak
For the Test Year Ended September 30, 2011



KCP&L GREATER MISSOURI OPERATIONS COMPANY

Analysis of KCP&L Greater Missouri Operations Company
For All Territories Served as L&P
Monthly Peak Demands
as a Percent of the Annual System Peak
(Weather Normalized and with Losses)
For the Test Year Ended September 30, 2011

Line	Description	L&P Retail MW (1)	Percent (2)
1	January	420	90.1
2	February	467	100.0
3	March	365	78.3
4	April	363	77.7
5	May	387	82.9
6	June	424	90.9
7	July	435	93.3
8	August	449	96.2
9	September	454	97.4
10	October	340	72.9
11	November	404	86.5
12	December	452	96.9

Source: GMO Allocators LP Rev 2-23-12.xls

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS L&P

Development of
Average and Excess Demand Allocator
Based on 4 Non-Coincident Peaks
For the Test Year Ended September 30, 2011

Line	Description	L&P Retail	Residential	General Service	Large General Service	Large Power Service	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)
1	Territory System Peak - kW	454,377					
2	Avg of 4 Highest Monthly NCP Values - kW	506,159	227,987	35,433	94,864	145,112	2,764
3	Energy Sales with Losses - MWh	2,291,176	830,788	115,519	404,334	916,442	24,093
4	Average Demand - kW	261,550	94,839	13,187	46,157	104,617	2,750
5	Average Demand - Percent	1.000000	0.362603	0.050419	0.176475	0.399988	0.010515
6	Class Excess Demand - kW	244,610	133,148	22,245	48,707	40,495	13
7	Class Excess Demand - Percent	1.000000	0.544328	0.090943	0.199123	0.165551	0.000055
	Allocator:						
8	Annual Load Factor * Average Demand	0.575623	0.208723	0.029022	0.101583	0.230242	0.006053
9	(1-LF) * Excess Demand	0.424377	0.231000	0.038594	0.084503	0.070256	0.000023
10	Average and Excess Demand Allocator	1.000000	0.439723	0.067616	0.186086	0.300498	0.006076

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	57.56%
1 - Load Factor	42.44%

Source: GMO Allocators LP Rev 2-23-12.xls

KCP&L Greater Missouri Operations - L&P Electric
2012 RATE CASE - Direct Filing
TY 9/30/11; Update TBD; K&M 8/31/12
Cost of Service

LINE NO.	DESCRIPTION	L&P RETAIL	RESIDENTIAL	GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**						
0020							
0030	OPERATING REVENUE						
0040	RETAIL SALES REVENUE	168,939,336	72,014,344	12,812,493	29,549,954	50,597,602	3,964,943
0050	OTHER SALES REVENUE	1,562,985	582,137	84,950	275,450	600,880	19,567
0060	OTHER OPERATING REVENUE	2,991,464	1,330,580	184,696	528,126	894,456	53,606
0070	TOTAL OPERATING REVENUE	173,493,786	73,927,061	13,082,140	30,353,530	52,092,938	4,038,116
0080							
0090	OPERATING EXPENSES						
0100	FUEL	36,722,622	13,181,165	1,848,826	6,512,462	14,792,931	387,237
0110	PURCHASED POWER	17,831,214	6,564,175	914,083	3,154,919	7,003,376	194,661
0120	OTHER OPERATION & MAINTENANCE EXPENSES	61,712,800	33,631,205	5,090,741	8,889,158	12,912,870	1,188,826
0130	DEPRECIATION EXPENSES (AFTER CLEARINGS)	17,748,037	8,897,717	1,196,723	2,830,703	4,267,487	555,408
0140	AMORTIZATION EXPENSES	1,983,397	1,002,940	145,685	315,766	482,658	36,348
0150	TAXES OTHER THAN INCOME TAXES	7,194,373	3,572,956	495,469	1,177,581	1,797,301	151,067
0160	FEDERAL AND STATE INCOME TAXES	6,627,522	142,704	1,010,671	2,047,368	2,830,416	596,363
0170	TOTAL ELECTRIC OPERATING EXPENSES	149,819,965	66,992,862	10,702,197	24,927,957	44,087,040	3,109,909
0180							
0190	NET ELECTRIC OPERATING INCOME	23,673,821	6,934,199	2,379,943	5,425,573	8,005,898	928,207
0200							
0210	RATE BASE						
0220	TOTAL ELECTRIC PLANT	721,546,534	356,259,823	48,646,172	119,133,096	181,752,896	15,754,547
0230	LESS: ACCUM. PROV. FOR DEPREC	239,143,711	121,118,290	16,156,137	38,165,575	56,710,833	6,992,877
0240	NET PLANT	482,402,823	235,141,533	32,490,035	80,967,521	125,042,063	8,761,669
0250	PLUS:						
0260	CASH WORKING CAPITAL	(6,941,278)	(3,175,169)	(503,889)	(1,196,419)	(1,910,890)	(154,910)
0270	MATERIALS & SUPPLIES	11,812,236	5,830,997	795,754	1,950,904	2,976,311	258,270
0280	EMISSION ALLOWANCES	288,847	103,678	14,542	51,225	116,356	3,046
0290	PREPAYMENTS	3,309,077	1,673,066	242,790	526,965	805,369	60,887
0300	FUEL INVENTORY	9,277,481	3,330,046	467,081	1,645,287	3,737,237	97,830
0310	DEFERRAL OF DSM/EE COSTS	5,984,173	2,631,380	404,628	1,113,571	1,798,232	36,361
0320	REGULATORY ASSETS	16,778,470	7,641,138	1,138,191	2,925,225	4,885,677	188,239
0330	LESS:						
0340	CUSTOMER ADVANCES FOR CONSTRUCTION	264,785	158,002	18,250	33,781	41,907	12,844
0350	CUSTOMER DEPOSITS	1,163,359	604,674	539,091	18,131	1,463	0
0360	TOTAL ACCUMULATED DEFERRED TAXES	41,953,115	20,709,754	2,826,253	6,928,958	10,570,861	917,290
0370	TOTAL RATE BASE	479,530,569	231,704,239	31,665,539	81,003,408	126,836,125	8,321,259
0380							
0390	RATE OF RETURN	4.937%	2.993%	7.516%	6.698%	6.312%	11.155%
0400	RELATIVE RATE OF RETURN	1.00	0.61	1.52	1.36	1.28	2.26

Notes:
Production Plant and Expense Allocated using A&E-4NCP.
SFR Off System Sales Revenue Allocated on Energy.

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS L&P

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using Modified ECOS at Present Rates
($ in Thousands)

Line	Rate Class	Current Revenues (1)	Current Rate Base (2)	Net Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Average Current ROR (6)	Difference in Income (7)	Revenue Increase (8)	Percentage Increase (9)
1	Residential	$ 73,927	$ 231,704	$ 6,934	2.993%	61	$ 11,439	$ 4,505	$ 7,392	10.0%
2	General Service	13,082	31,666	2,380	7.516%	152	1,563	(817)	(1,340)	-10.2%
3	Large General Service	30,354	81,003	5,426	6.698%	136	3,999	(1,427)	(2,341)	-7.7%
4	Large Power Service	52,093	126,836	8,006	6.312%	128	6,262	(1,744)	(2,862)	-5.5%
5	Total Lighting	4,038	8,321	928	11.155%	226	411	(517)	(849)	-21.0%
6	Total	$ 173,494	$ 479,531	$ 23,674	4.937%	100	$ 23,674	$ -	$ -	0.0%

Source: Schedule MEB-COS-4

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS L&P

Recommended Cost of Service Adjustments
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 25% Toward Cost Of Service (2)	Adjusted Current Revenue (3)	Percent of Adjusted Current Revenue (4)
1	Residential	$ 73.9	$ 1.8	$ 75.8	43.68%
2	General Service	13.1	(0.3)	12.7	7.35%
3	Large General Service	30.4	(0.6)	29.8	17.16%
4	Large Power Service	52.1	(0.7)	51.4	29.61%
5	Total Lighting	4.0	(0.2)	3.8	2.21%
6	Subtotal	$ 173.5	$ -	$ 173.5	100.00%

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS L&P

Development of
Average and Excess Demand Allocator
Based on 2 Non-Coincident Peaks
For the Test Year Ended September 30, 2011

Line	Description	L&P Retail	Residential	General Service	Large General Service	Large Power Service	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)
1	Territory System Peak - kW	454,377					
2	Avg of 2 Highest Monthly NCP Values - kW	511,446	226,930	35,136	97,562	149,055	2,764
3	Energy Sales with Losses - MWh	2,291,176	830,788	115,519	404,334	916,442	24,093
4	Average Demand - kW	261,550	94,839	13,187	46,157	104,617	2,750
5	Average Demand - Percent	1.000000	0.362603	0.050419	0.176475	0.399988	0.010515
6	Class Excess Demand - kW	249,897	132,091	21,949	51,405	44,438	13
7	Class Excess Demand - Percent	1.000000	0.528583	0.087831	0.205705	0.177827	0.000054
	Allocator:						
8	Annual Load Factor * Average Demand	0.575623	0.208723	0.029022	0.101583	0.230242	0.006053
9	(1-LF) * Excess Demand	0.424377	0.224319	0.037273	0.087297	0.075466	0.000023
10	Average and Excess Demand Allocator	1.000000	0.433041	0.066296	0.188879	0.305708	0.006076

Notes:
Line 4 equals Line 3 ÷ 8.760
Line 6 equals Line 2- Line 4

System Annual Load Factor	57.56%
1 - Load Factor	42.44%

Source: GMO Allocators LP Rev 2-23-12.xls

KCP&L Greater Missouri Operations - L&P Electric
2012 RATE CASE - Direct Filing
TY 9/30/11; Update TBD; K&M 8/31/12
Cost of Service

LINE NO.	DESCRIPTION	L&P RETAIL	RESIDENTIAL	GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**						
0020							
0030	OPERATING REVENUE						
0040	RETAIL SALES REVENUE	168,939,336	72,014,344	12,812,493	29,549,954	50,597,602	3,964,943
0050	OTHER SALES REVENUE	1,562,985	582,137	84,950	275,450	600,880	19,567
0060	OTHER OPERATING REVENUE	2,991,464	1,329,595	184,502	528,537	895,224	53,606
0070	TOTAL OPERATING REVENUE	173,493,786	73,926,076	13,081,945	30,353,942	52,093,706	4,038,116
0080							
0090	OPERATING EXPENSES						
0100	FUEL	36,722,622	13,181,165	1,848,826	6,512,462	14,792,931	387,237
0110	PURCHASED POWER	17,831,214	6,564,175	914,083	3,154,919	7,003,376	194,661
0120	OTHER OPERATION & MAINTENANCE EXPENSES	61,712,800	33,437,319	5,052,416	8,970,211	13,064,041	1,188,812
0130	DEPRECIATION EXPENSES (AFTER CLEARINGS)	17,748,037	8,838,373	1,184,993	2,855,512	4,313,756	555,403
0140	AMORTIZATION EXPENSES	1,983,397	995,638	144,242	318,818	488,351	36,347
0150	TAXES OTHER THAN INCOME TAXES	7,194,373	3,546,497	490,239	1,188,642	1,817,931	151,065
0160	FEDERAL AND STATE INCOME TAXES	6,627,522	286,639	1,039,122	1,987,196	2,718,192	596,374
0170	TOTAL ELECTRIC OPERATING EXPENSES	149,819,965	66,849,807	10,673,920	24,987,761	44,198,578	3,109,898
0180							
0190	NET ELECTRIC OPERATING INCOME	23,673,821	7,076,269	2,408,025	5,366,181	7,895,128	928,218
0200							
0210	RATE BASE						
0220	TOTAL ELECTRIC PLANT	721,546,534	353,605,824	48,121,574	120,242,596	183,822,190	15,754,351
0230	LESS: ACCUM. PROV. FOR DEPREC	239,143,711	120,344,119	16,003,111	38,489,216	57,314,445	6,992,820
0240	NET PLANT	482,402,823	233,261,705	32,118,462	81,753,380	126,507,745	8,761,531
0250	PLUS:						
0260	CASH WORKING CAPITAL	(6,941,278)	(3,162,231)	(501,332)	(1,201,828)	(1,920,978)	(154,909)
0270	MATERIALS & SUPPLIES	11,812,236	5,787,549	787,166	1,969,067	3,010,187	258,267
0280	EMISSION ALLOWANCES	288,847	103,678	14,542	51,225	116,356	3,046
0290	PREPAYMENTS	3,309,077	1,660,901	240,385	532,051	814,854	60,886
0300	FUEL INVENTORY	9,277,481	3,330,046	467,081	1,645,287	3,737,237	97,830
0310	DEFERRAL OF DSM/EE COSTS	5,984,173	2,591,395	396,725	1,130,287	1,829,408	36,359
0320	REGULATORY ASSETS	16,778,470	7,562,805	1,122,707	2,957,972	4,946,753	188,233
0330	LESS:						
0340	CUSTOMER ADVANCES FOR CONSTRUCTION	264784.6154	158002.2101	18250.32673	33781.23248	41907.01589	12843.83021
0350	CUSTOMER DEPOSITS	1,163,359	604,674	539,091	18,131	1,463	0
0360	TOTAL ACCUMULATED DEFERRED TAXES	41,953,115	20,555,441	2,795,751	6,993,468	10,691,177	917,279
0370	TOTAL RATE BASE	479,530,569	229,817,730	31,292,645	81,792,060	128,307,015	8,321,120
0380							
0390	RATE OF RETURN	4.937%	3.079%	7.695%	6.561%	6.153%	11.155%
0400	RELATIVE RATE OF RETURN	1.00	0.62	1.56	1.33	1.25	2.26

Notes:
Production Plant and Expense Allocated using A&E-2NCP.
SFR Off System Sales Revenue Allocated on Energy.

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FOR ALL TERRITORIES SERVED AS L&P

Development of
4 CP Demand Allocator
For the Test Year Ended September 30, 2011

Line	Description	L&P Retail	Residential	General Service	Large General Service	Large Power Service	Lighting
		(1)	(2)	(3)	(4)	(5)	(6)
1	4 CP Demand - kW	434,399	189,647	27,040	78,933	138,779	-
2	4 CP Demand - Percent	1.000000	0.436573	0.062247	0.181707	0.319473	-

Source: GMO Allocators LP Rev 2-23-12.xls

KCP&L Greater Missouri Operations - L&P Electric
2012 RATE CASE - Direct Filing
TY 9/30/11; Update TBD; K&M 8/31/12
Cost of Service

LINE NO.	DESCRIPTION	L&P RETAIL	RESIDENTIAL	GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
0010	**SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE**						
0020							
0030	OPERATING REVENUE						
0040	RETAIL SALES REVENUE	168,939,336	72,014,344	12,812,493	29,549,954	50,597,602	3,964,943
0050	OTHER SALES REVENUE	1,562,985	582,137	84,950	275,450	600,880	19,567
0060	OTHER OPERATING REVENUE	2,991,464	1,330,116	183,905	527,480	897,253	52,710
0070	TOTAL OPERATING REVENUE	173,493,786	73,926,597	13,081,348	30,352,885	52,095,735	4,037,220
0080							
0090	OPERATING EXPENSES						
0100	FUEL	36,722,622	13,181,165	1,848,826	6,512,462	14,792,931	387,237
0110	PURCHASED POWER	17,831,214	6,564,175	914,083	3,154,919	7,003,376	194,661
0120	OTHER OPERATION & MAINTENANCE EXPENSES	61,712,800	33,539,786	4,934,941	8,762,096	13,463,465	1,012,512
0130	DEPRECIATION EXPENSES (AFTER CLEARINGS)	17,748,037	8,869,736	1,149,036	2,791,813	4,436,009	501,443
0140	AMORTIZATION EXPENSES	1,983,397	999,497	139,818	310,981	503,393	29,708
0150	TAXES OTHER THAN INCOME TAXES	7,194,373	3,560,480	474,207	1,160,241	1,872,439	127,006
0160	FEDERAL AND STATE INCOME TAXES	6,627,522	210,571	1,126,332	2,141,695	2,421,671	727,254
0170	TOTAL ELECTRIC OPERATING EXPENSES	149,819,965	66,925,410	10,587,243	24,834,207	44,493,285	2,979,819
0180							
0190	NET ELECTRIC OPERATING INCOME	23,673,821	7,001,187	2,494,105	5,518,677	7,602,451	1,057,401
0200							
0210	RATE BASE						
0220	TOTAL ELECTRIC PLANT	721,546,534	355,008,437	46,513,511	117,393,821	189,289,692	13,341,073
0230	LESS: ACCUM. PROV. FOR DEPREC	239,143,711	120,753,261	15,534,040	37,658,229	58,909,314	6,288,867
0240	NET PLANT	482,402,823	234,255,176	30,979,471	79,735,592	130,380,377	7,052,205
0250	PLUS:						
0260	CASH WORKING CAPITAL	(6,941,278)	(3,169,069)	(493,493)	(1,187,940)	(1,947,632)	(143,144)
0270	MATERIALS & SUPPLIES	11,812,236	5,810,511	760,841	1,922,430	3,099,694	218,760
0280	EMISSION ALLOWANCES	288,847	103,678	14,542	51,225	116,356	3,046
0290	PREPAYMENTS	3,309,077	1,667,330	233,014	518,993	839,915	49,824
0300	FUEL INVENTORY	9,277,481	3,330,046	467,081	1,645,287	3,737,237	97,830
0310	DEFERRAL OF DSM/EE COSTS	5,984,173	2,612,527	372,497	1,087,367	1,911,782	0
0320	REGULATORY ASSETS	16,778,470	7,604,203	1,075,245	2,873,890	5,108,128	117,004
0330	LESS:						
0340	CUSTOMER ADVANCES FOR CONSTRUCTION	264784.6154	158002.2101	18250.32673	33781.23248	41907.01589	12843.83021
0350	CUSTOMER DEPOSITS	1,163,359	604,674	539,091	18,131	1,463	0
0360	TOTAL ACCUMULATED DEFERRED TAXES	41,953,115	20,636,994	2,702,252	6,827,830	11,009,077	776,962
0370	TOTAL RATE BASE	479,530,569	230,814,732	30,149,606	79,767,101	132,193,410	6,605,720
0380							
0390	RATE OF RETURN	4.937%	3.033%	8.272%	6.918%	5.751%	16.007%
0400	RELATIVE RATE OF RETURN	1.00	0.61	1.68	1.40	1.16	3.24

Notes:
Production Plant and Expense Allocated using 4CP.
SFR Off System Sales Revenue Allocated on Energy.